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FEE TRANSMITTAL

Patent fees are subject to annual revision on October 1.
These are the fees effective October 1, 1997.
Small Entity payments must be supported by a small entity statement,
otherwise large entity fees must be paid. See Forms PTO/SB/09-12.

TOTAL AMOUNT OF PAYMENT (\$)**918.00**

Complete if Known

Application Number	Unknown
Filing Date	Herewith
First Named Inventor	Robert E. Dutton
Examiner Name	Unknown
Group / Art Unit	Unknown
Attorney Docket No.	7003/036

METHOD OF PAYMENT (check one)

1. ☒ The Commissioner is hereby authorized to charge indicated fees and credit any over payments to:
- Deposit Account Number **04-1697**
- Deposit Account Name **Duft, Graziano & Forest, P. C.**
- ☒ Charge Any Additional Fee Required Under 37 CFR 1.16 and 1.17 ☐ Charge the Issue Fee Set in 37 CFR 1.18 at the Mailing of the Notice of Allowance

2. ☒ Payment Enclosed:
- ☒ Check ☐ Money Order ☐ Other

FEE CALCULATION

1. BASIC FILING FEE

Large Entity Fee Code (\$)	Small Entity Fee Code (\$)	Fee Description	Fee Paid
101 790	201 395	Utility filing fee	790
106 330	206 165	Design filing fee	
107 540	207 270	Plant filing fee	
108 790	208 395	Reissue filing fee	
114 150	214 75	Provisional filing fee	
SUBTOTAL (1)			790

2. EXTRA CLAIM FEES

Total Claims **24** -20** = **4** X **22** = **88**

Independent Claims **3** -3** = **0** X = **0**

Multiple Dependent =

**or number previously paid, if greater; For Reissues, see below

Large Entity Fee Code (\$)	Small Entity Fee Code (\$)	Fee Description	Fee Paid
103 22	203 11	Claims in excess of 20	
102 82	202 41	Independent claims in excess of 3	
104 270	204 135	Multiple dependent claim, if not paid	
109 82	209 41	** Reissue independent claims over original patent	
110 22	210 11	** Reissue claims in excess of 20 and over original patent	
SUBTOTAL (2)			88

FEE CALCULATION (continued)

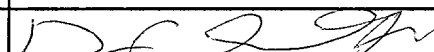
3. ADDITIONAL FEES

Large Entity Fee Code (\$)	Small Entity Fee Code (\$)	Fee Description	Fee Paid
105 130	205 65	Surcharge - late filing fee or oath	
127 50	227 25	Surcharge - late provisional filing fee or cover sheet.	
139 130	139 130	Non-English specification	
147 2,520	147 2,520	For filing a request for reexamination	
112 920*	112 920*	Requesting publication of SIR prior to Examiner action	
113 1,840*	113 1,840*	Requesting publication of SIR after Examiner action	
115 110	215 55	Extension for reply within first month	
116 400	216 200	Extension for reply within second month	
117 950	217 475	Extension for reply within third month	
118 1,510	218 755	Extension for reply within fourth month	
128 2,060	228 1,030	Extension for reply within fifth month	
119 310	219 155	Notice of Appeal	
120 310	220 155	Filing a brief in support of an appeal	
121 270	221 135	Request for oral hearing	
138 1,510	138 1,510	Petition to institute a public use proceeding	
140 110	240 55	Petition to revive - unavoidable	
141 1,320	241 660	Petition to revive - unintentional	
142 1,320	242 660	Utility issue fee (or reissue)	
143 450	243 225	Design issue fee	
144 670	244 335	Plant issue fee	
122 130	122 130	Petitions to the Commissioner	
123 50	123 50	Petitions related to provisional applications	
126 240	126 240	Submission of Information Disclosure Stmt	
581 40	581 40	Recording each patent assignment per property (times number of properties)	40
146 790	246 395	Filing a submission after final rejection (37 CFR 1.129(a))	
149 790	249 395	For each additional invention to be examined (37 CFR 1.129(b))	
Other fee (specify) _____			
Other fee (specify) _____			
SUBTOTAL (3)			40

* Reduced by Basic Filing Fee Paid

SUBMITTED BY

Typed or Printed Name **Dan Cleveland, Jr**

Signature 

Date **9/30/98**

Complete (if applicable)

Reg. Number **36,106**

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APPLICATION NO. FILING DATE DOCKET NO.

TRANSIENT BUBBLE REMEDIATION IN CORIOLIS FLOWMETERS
TITLE OF INVENTION

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BOX PATENT APPLICATION
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WASHINGTON, DC 20231

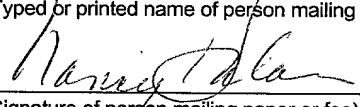
"Express Mail" mailing label number EL055940881US
Date of Deposit September 30, 1998

I hereby certify that these papers including the following:

1. Application (24 pages)
2. Drawings (2 sets) (6 pages each set)
3. Declaration (1 page)
4. Assignment (2 pages)
5. Assignment Recordation Cover Sheet (2 pages)
6. Fee Transmittal (1 page) (2 copies)
7. Check No. 5419 in the amount of \$918.00
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are being deposited with the United States Postal Service "Express Mail" service on the date indicated above and is addressed to: Box PATENT APPLICATION, Commissioner of Patents and Trademarks, Washington, DC 20231

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09/30/98

TRANSIENT BUBBLE REMEDIATION IN CORIOLIS FLOWMETERS

BACKGROUND OF THE INVENTION

1. Field of the Invention

5 The present invention pertains to Coriolis effect mass flowmeters. More particularly, the Coriolis effect mass flowmeters contain self diagnostics that improve the accuracy obtainable from the meters in measuring two phase flow including mixtures of gas and liquid, or in identifying measurements that may be affected by the deposition of scale or wax inside the meter.

2. Statement of the Problem

10 Coriolis flowmeters directly measure the rate of mass flow through a conduit. As disclosed in the art, such as in U.S. Pat. Nos. 4,491,025 (issued to J.E. Smith et al. on Jan 1, 1985 and hereinafter referred to as the U.S. Pat. No. 4,491,025) and Re. 31,450 (issued to J.E. Smith on Feb. 11, 1982 and hereinafter referred to as the U.S. Pat. No. Re. 31,450), these flowmeters have one or more flowtubes of straight or curved configuration. Each flowtube configuration in a Coriolis mass flowmeter has a set of natural vibration modes, which may be of a simple bending, torsional or coupled type. Fluid flows into the flowmeter from the adjacent pipeline on the inlet side, is directed through the flowtube or tubes, and exits the flowmeter through the outlet side of the flowmeter. The natural vibration modes of the vibrating, fluid filled system are defined in part by the combined mass of the flowtubes and the fluid within the flowtubes. Each flow conduit is driven to oscillate at resonance in one of these natural modes.

20 When there is no flow through the flowmeter, all points along the flowtube oscillate with identical phase. As fluid begins to flow, Coriolis accelerations cause each point along the flowtube to have a different phase. The phase on the inlet side of the flowtube lags the driver, while the phase on the outlet side leads the driver. Sensors can be placed on the flowtube to produce sinusoidal signals representative of the motion of the flowtube. The phase difference between two sensor signals is proportional to the mass flow rate of fluid through the flowtube. A complicating factor

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in this measurement is that the density of typical process fluids varies. Changes in density cause the frequencies of the natural modes to vary. Since the flowmeter's control system maintains resonance, the oscillation frequency varies in response. Mass flow rate in this situation is proportional to the ratio of phase difference and oscillation frequency.

U.S. Pat. No. Re. 31,450 discloses a Coriolis flowmeter that avoids the need of measuring both phase difference and oscillation frequency. Phase difference is determined by measuring the time delay between level crossings of the two sinusoidal signals. When this method is used, the variations in the oscillation frequency cancel, and mass flow rate is proportional to the measured time delay. This measurement method is hereinafter referred to as a time delay measurement.

A problem in currently available Coriolis flow measurement apparatus is a limited suitability to gas applications. Gases are less dense than liquids and consequently, at the same flow velocities, smaller Coriolis accelerations are generated. This situation requires a higher sensitivity flowmeter. Alternatively, a flowmeter with conventional sensitivity could be used, if the flow velocity is increased to achieve the same Coriolis accelerations. Unfortunately, this alternative leads to a flowmeter having a sensitivity that is not constant.

The problems with gas flow through Coriolis flowmeters are exacerbated in systems with multiphase flow including liquids and gas. The gas damps the system with the effect of reducing sensitivity to measurement. This damping effect can be so severe that the meter cannot perform flow measurements.

Situations involving the use of Coriolis flowmeters to measure multiphase flow often arise in the petroleum industry where oil wells produce oil, gas, and water. Gas wells similarly produce gas, condensate and water. US patent no. 5,654,502 describes a well test system where a manifold is configured to flow a selected well through a test separator, which separates the production from the well into respective portions including gas, oil or condensate, and water. A Coriolis flowmeter is used to measure the mass flow rate of the respective oil and water components. The accuracy of the flowmeter measurements is enhanced by using an electronically

derived water cut measurement to correct the measured density of the segregated oil phase for residual water content. This correction process is difficult or impossible to use, in some situations, because not all wells are coupled with a test separator. It is sometimes desirable to measure the flow from a well directly and without the use or expense of a test separator. In these situations, the presence of gas in the system can be a critical limiting factor in the accuracy of measurements that are obtainable from the meter.

United States Patent No. 5,029,482 teaches the use of empirically-derived correlations that are obtained by flowing combined gas and liquid flow streams having known mass percentages of the respective gas and liquid components through a Coriolis meter. The empirically-derived correlations are then used to calculate the percentage of gas and the percentage of liquid in a combined gas and liquid flow stream of unknown gas and liquid percentages based upon a direct Coriolis measurement of the total mass flow rate. The '482 patent does not address remediation of the effects of gas damping in the system measurements, though this damping effect may have an effect upon the empirical correlations.

Accordingly, there is a true need for a Coriolis flowmeter that is less sensitive to the effects of gas damping upon density measurements in multiphase flow.

SOLUTION

The present invention overcomes the problems outlined above and advances the art by providing a Coriolis flowmeter that is less sensitive to the effects of gas damping upon density measurements in multiphase flow. The meter electronics are programmed for special processing that compares drive gain against a threshold value as an indicator of multiphase flow.

The Coriolis flowmeter is broadly capable of use as a vibrating densitometer in multiphase flow environments including combinations of gas and liquids, gas and solids, or solids and liquids. The flowmeter includes at least one flowtube and a driver for vibrating the flowtube at a fundamental frequency corresponding to a density of material flowing through the flowtube. The meter electronics monitor drive gain in the vibrating flowtube for a change in value to determine the existence of

5 multiphase flow through said flowtube. This change in value is typically a comparison against a threshold value where multiphase flow including gas and liquid is indicated by the drive gain exceeding the threshold value. A second comparison may be made against a second threshold value to indicate the existence of multiphase flow including gas and solids, liquid and solids, or liquid, gas and solids, which may exhibit similar damping effects to those of gas and liquid systems. The meter electronics respond to the existence of multiphase flow in said flowtube for the duration of the multiphase flow. This response is typically the provision of historical density data for use in determining volumetric flow rates from real time mass flow rate data from said meter. Other useful density values for use during the interval of damped multiphase flow may include density measurements obtained from selected components of the multiphase fluid.

10 The historical density values for use during the interval of damped multiphase flow are typically averaged over an interval of time to provide an average density value. These values may also be subjected to statistical analysis to eliminate or reduce spurious measurements from being included in the average density value. As an alternative to using historical measurement data, density values for representative fluids may be obtained from laboratory measurements or from empirically derived correlations for fluid properties including density.

20 The Coriolis flowmeter is intended for use in any environment where multiphase flow exists, where multiphase flow is defined as flow including at least two states of matter: solid, liquid or gas. The flowmeter is especially useful in multiphase systems including gas and liquid or gas and solids. These environments are especially common in the petroleum industry where a producing oil well or gas well can flow mist, bubbles, or other multiphase fluid systems. The flowmeter is especially useful in performing flow tests upon wells to determine the volumetric flow rates of a well as to water, gas, and oil or condensate. In these situations, the meter electronics can take action to overcome the problem of gas damping directly by increasing the backpressure on the well to force gas into solution or by indicating an alarm condition to request operator intervention.

The invention also pertains to control software including instructions for accomplishing the objectives of the invention. Specifically, the instructions are operational when executed by a processor to direct the processor to receive drive gain inputs from a Coriolis meter and process the drive gain inputs, process the drive gain inputs to determine the existence of multiphase flow through the Coriolis flowmeter by comparing the drive gain inputs against a threshold value indicative of multiphase flow, and providing outputs including a historical density value not representative of actual density measurements for the duration of the multiphase flow. These instructions are stored on a machine readable storage medium for retrieval as needed.

BRIEF DESCRIPTION OF THE DRAWINGS

FIGURE 1 depicts a Coriolis flowmeter;

FIG. 2 is a block diagram of the meter electronics in the Coriolis flowmeter;

FIG. 3 depicts a schematic diagram of a vibrating spring and weight system;

FIG. 4 depicts a schematic diagram of a vibrating spring and weight system like that of FIG., 3 but additionally including a gas damper that is analogous to gas in a multiphase flow system;

FIG. 5 depicts a plot of transmissivity versus vibrational frequency including a comparison between a hypothetical liquid system and a hypothetical liquid system that is damped by the addition of a gas component in multiphase flow;

FIG. 6 depicts a plot of drive gain versus time during a transient bubble event that requires remediation;

FIG. 7 depicts a schematic process control diagram demonstrating a method for remediation of the transient bubble event shown in FIG. 6; and

FIG. 8 depicts a schematic block diagram of a well test system incorporating control circuitry capable of implementing the method shown in FIG. 7.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT**Coriolis Flowmeter in General -FIG. 1**

FIG. 1 illustrates a Coriolis flowmeter 5 comprising a flowmeter assembly 10 and meter electronics 20. Meter electronics 20 is connected to meter assembly 10 via leads 100 to provide density, mass flow rate, volume flow rate, totalized mass flow and other information over path 26. It should be apparent to those skilled in the art that the present invention can be used by any type of Coriolis flowmeter regardless of the number of drivers or the number of pick-off sensors.

Flowmeter assembly 10 includes a pair of flanges 101 and 101', manifold 102 and flowtubes 103A and 103B. Connected to flowtubes 103 A and 103 B are driver 104 and pick-off sensors 105 and 105'. Brace bars 106 and 106' serve to define the axes W and W' about which each flowtube 103A and 103B oscillates.

When flowmeter assembly 10 is inserted into a pipeline system (not shown) which carries the material being measured, material enters flowmeter assembly 10 through flange 101, passes through manifold 102 where the material is directed to enter flowtubes 103A and 103B, flows through flowtubes 103 A and 103B and back into manifold 102 where it exits meter assembly 10 through flange 101'.

Flowtubes 103A and 103B are selected and appropriately mounted to manifold 102 so as to have substantially the same mass distribution, moments of inertia, and elastic modules about bending axes W-W and W'-W' respectively. The flowtubes extend outwardly from the manifold in an essentially parallel fashion.

Flowtubes 103A-B are driven by driver 104 in opposite directions about their respective bending axes W and W' and at what is termed the first out of bending fold of the flowmeter. Driver 104 may comprise one of many well known arrangements, such as a magnet mounted to flowtube 103A and an opposing coil mounted to flowtube 103B. An alternating current is passed through the opposing coil to cause both tubes to oscillate. A suitable drive signal is applied by meter electronics 20, via lead 110 to driver 104.

The description of FIG. 1 is provided merely as an example of the operation of a Coriolis flowmeter and is not intended to limit the teaching of the present

invention. The present invention is equally applicable to other types of Coriolis flowmeter including single tube meters, as well as those having multiple pickoffs or multiple drivers.

5 Meter electronics 20 receives the right and left velocity signals appearing on leads 111 and 111', respectively. Meter electronics 20 produces the drive signal on lead 110 causing driver 104 to oscillate flowtubes 103A and 103B. The present invention as described herein, can produce multiple drive signals from multiple drivers. Meter electronics 20 process left and right velocity signals to compute mass flow rate and provide the validation system of the present invention. Path 26
10 provides an input and an output means that allows meter electronics 20 to interface with an operator.

Meter Electronics 20 in General - FIG. 2

FIG. 2 illustrates a block diagram of the components of meter electronics 20 which perform the processes related to the present invention. Paths 111 and 111' transmit the left and right velocity signals from flowmeter assembly 10 to meter electronics 20. The velocity signals are received by analog to digital (A/D) convertor 203 in meter electronics 20. A/D convertor 203 converts the left and right velocity signals to digital signals usable by processor 201 and transmits the digital signals over path 213 to I/O bus 210. The digital signals are carried by I/O bus 210 to processor 201. Driver signals are transmitted over I/O bus 210 to path 212 which applies the signals to digital to analog (D/A) convertor 202. The analog signals from D/A convertor 202 are transmitted to driver 104 via path 110. Path 26 is connected to I/O bus 210 and carries signals to input and output means (not shown) which allow meter electronics 20 to receive data from and convey data to an operator.

25 Processor 201 reads instructions for performing the various functions of the flowmeter including but not limited to computing mass flow rate of a material, computing volume flow rate of a material, and computing density of a material from a Read Only Memory (ROM) 220 via path 221. The data as well as instructions for performing the various functions are stored in a Random Access Memory (RAM) 230. Processor 201 performs read and write operations in RAM memory 230 via
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path 231. In a larger sense, meter electronics 20 include additional control instrumentation and other processors that may optionally be connected to meter electronics 20 on path 26.

Fluid Density Calculations

FIG. 3 depicts an undamped dynamic spring assembly 300 that operates on the same physical principles as flowtubes 103 A and 103 B of Coriolis flowmeter 5 (see FIG. 1) in single phase flow. Spring 302 is connected to an anchor 304 and a mass 306. The mass 306 reciprocates or vibrates on a path parallel to double headed arrow 308. The natural frequency, f_n of assembly 300 is:

$$(1) \quad f_n = \frac{1}{2\pi} \sqrt{\frac{K_s}{m}}$$

where K_s is the spring constant of spring 302 and m is the mass of mass 306. IN the case of Coriolis flowmeter 5, m is the combined weight of the flowtubes 103 A and 103 together with the mass of material inside the tubes.

Where equation (1) is applied to a flowtube 103A or 103B, it becomes:

$$(2) \quad \rho = \frac{A}{f_n^2} - B$$

where A and B are calibration constants determined in a conventional manner for Coriolis flowmeters, ρ is the density of the media flowing through the flowtube, and f_n is the natural frequency. Thus, by knowing the natural frequency, one can determine the density of the fluid.

Coriolis flowmeters measure mass flow rates by measuring the Coriolis twisting of a vibrating sensor tube, e.g., one of flowtubes 103A and 103B (see FIG. 1). The sensor tube vibrations have the effect of changing the angular momentum of fluid or fluids flowing inside the tube. The Coriolis twisting force is relatively small, and the flowtubes are relatively stiff. In order to make the tube vibrate with sufficient

amplitude to make the Coriolis twisting force detectable, the meter electronics 20 provide a drive voltage to drive coil 104 that vibrates the flowtube or tube at its natural frequency. Thus, processor 201 (see FIG. 2) provides output that continuously maximizes the transmissivity ratio or drive gain in a conventional manner for Coriolis flowmeters. For example, the drive voltage is typically increased as the transmissivity ratio or drive gain decreases. At the same time, the drive voltage cannot be increased beyond some maximum limiting value, or else the voltage will eventually become too great with the result that the meter is damaged by excessive voltage or excessive vibration amplitudes.

The Effect of Gas Damping on the System

FIG. 4 depicts a damped dynamic spring and mass assembly 400 that operates on the same physical principles as flowtubes 103 A and 103 B of Coriolis flowmeter 5 (see FIG. 1) in multiphase phase flow including gas and liquid. Where possible, like numbering in FIG. 4 has been retained for identical elements in FIG. 4. FIG. 4 differs from FIG. 3 by the addition of a damper 402, which has the effect of reducing the amplitude of vibration along path 308. Equations (1) and (2) still apply to the system shown in FIG. 4, but the overall magnitude of vibration is less due to damper 402.

FIG. 5 is a plot of hypothetical data demonstrating the practical effects of gas damping on the frequency response of flowtubes 103 A and 103 B in Coriolis flowmeter 5 (see also FIG. 1). The log of transmissivity is plotted as a function of the frequency of alternating voltage applied to the drive coil 104, e.g., at frequencies f_0 , f_1 , and f_2 . The transmissivity ratio T_r equals the pickoff output divided by the drive input, i.e., T_r is the drive gain:

$$(3) \quad T_r = \frac{OUTPUT}{INPUT} = \frac{V_{ac} PICKOFF COIL}{V_{ac} DRIVE COIL}$$

where V_{ac} pickoff coil is the alternating voltage on leads 111 and 111' from pickoffs 105 and 105' and V_{ac} drive coil is the alternating voltage on lead 110 to drive coil 104. These voltages may be adjusted proportionally by a calibration constant to

account for differences in scale between the drive coil 104 and pickoffs 105 and 105'.

A first curve 500 corresponds to the undamped system of Equation (1) and FIG. 3, i.e., no gas is present in the fluid being measured. A second curve 502 corresponds to the damped system of Equation (3). Both curves 500 and 502 have an optimal value 504 and 504', respectively, at the natural frequency f_n . The region 506 of curves 500 and 502 to the left of f_n represents a situation where the flowtubes 103A and 103B (see FIG. 1) are vibrating in phase. The region 508 of curves 500 and 502 to the right of f_n represents a situation where the flowtubes 103A and 103B (see FIG. 1) are vibrating out of phase. The optimal point 504' is more difficult to detect than optimal point 504 due to the reduced amplitude of optimal point 504'. As the amplitude decreases due to gas damping, the Coriolis flowmeter 5 (see FIG. 1) can no longer perform effective flow measurements, depending upon the sensitivity of the flowmeter.

The meter electronics 20 are designed to monitor drive gain or transmissivity and to optimize the amplitude of transmissivity based upon a ratio of the voltage at the pickoff coil divided by the voltage at the drive coil. This optimization is performed based upon a slope analysis of curve 500. For example, a first forward difference taken from new data generated by a faster frequency of vibration at the drive coil will produce a slope having a zero value (optimized condition), a negative value (region 508), or a positive value (region 506). The meter electronics then drive the vibration faster or slower, as need is indicated by the slope of the data, until an optimized transmissivity is obtained.

FIG. 6 is a plot of hypothetical data showing the relationship between drive gain and time for an event 600 where a transient bubble enters a Coriolis flowmeter 5 (see FIG. 1) at time 602 and exits at time 604. Drive gain is expressed as a percent in FIG. 6, and plotted as a function of time at intervals, e.g., t_1 , t_2 , and t_3 . According to the concept of the present invention, processor 201 (see also FIG. 2) is programmed with a threshold value 606 based upon drive gain or transmissivity. Where the drive gain or transmissivity of curve 608 exceeds threshold 606, processor 201 ceases to use a density value calculated in

the conventional manner according to Equation (2). Processor 201 then proceeds to calculate density according to the flow chart shown in FIG. 7.

The effects shown in FIGS. 5-7 are similar to the effects of multiphase flow including liquids and solids, e.g., with paraffin, sand, or scale in the fluid, or with scale having actually built up on the internal flowtube walls of flowtubes 103A and 103B. Thus, a system capable of detecting gas and liquid multiphase flow is also capable of detecting, using the same principles; multiphase flow including gas and solids, liquid and solids or scale internal to the flowtubes.

Transient Bubble Remediation Mode

It is always preferred to use measurements obtained according to Equation (2) for meter outputs including density values; however, it is not always possible to use Equation (2) due to the deleterious effects of gas damping in multiphase flow. FIG. 7 depicts a process P700 for remediation of density values when a transient bubble enters Coriolis flowmeter 5 with the effect of gas damping the system. Process P700 has been developed according to the premise that, while gas damping may create real-time measurement difficulties, the next best value for density obtainable from the Coriolis flowmeter is a recently measured density. The respective steps of process P700 are described in the context of reference numbers also appearing in FIG. 6.

In step P702, processor 201 determines that the drive gain has exceeded threshold 606 as a consequence of curve 608 having crossed threshold 606 at time 602. Due to the fact that the portion of curve 608 preceding time 602 may have some noise due to a bubble that is about to enter the meter, during step P704 processor 201 looks back over a predetermined time interval 610 to an averaging interval 612. Averaging interval 612 may correspond to a single data point, but it preferably comprises an interval including multiple data points for the purpose of smoothing spurious measurements 614 that may spike upwards without exceeding threshold 606.

In step P706, processor 201 determines whether any of the measurements in averaging interval 612 exceed threshold 606. If so, in step P708, a multiple or

fraction of look back interval 610 may be calculated used to arrive at a new averaging interval 612 through a repetition of step P704. If repeated attempts through step P706 fail to arrive at an interval 612 having no points greater than threshold 606, then spurious measurements e.g., measurement 614, including those greater than threshold 606 can be eliminated by statistical analysis. This statistical analysis can include calculating a standard deviation and ignoring all numbers outside the standard deviation or ignoring all numbers greater than threshold 606, so long as some measurements in averaging interval 612 are less than threshold 606. Alternatively, the processor 201 can be programmed to output a preselected density value, such as may be obtained from laboratory measurements.

Step P710 includes averaging the density values over averaging interval 612 to provide an average representative density value corresponding to averaging interval 612. The values that are used to calculate this average may be adjusted by statistical analysis as discussed above in relation to step P706. In circumstances where meter diagnostics show that the flowmeter is not operating correctly to produce a mass flow rate measurement due to gas damping, the meter output for mass flow rate can also be averaged according to these same principles.

According to step P712, the processor 201 provides as a meter output the average density value obtained from step P710 until such time as curve 608 falls below threshold 606 at time 604. Accordingly, process P700 concludes at step P714 with processor 201 leaving the transient bubble remediation mode and returning to meter output consisting of measurements performed according to Equation (2).

The precise levels or durations for threshold 606, look back interval 610, and averaging interval 610 are associated with the type and size of meter, as well as the intended environment of use. For example, these values are different for meters installed on a well making one thousand barrels of oil per day versus a well making one barrel of oil. In practice, an operator determines the threshold 606 at which the Coriolis flowmeter 5 operates without bubbles. This determination is made by a combination of experience, trial and error, manufacturer's recommendations, or recording over time in the intended environment of use. The operator enters this

value into the meter electronics 20 as a set value for use in process P700. The meter electronics continuously monitor the drive gain level. Applications of transient bubble remediation technology are not limited to petroleum industry applications, and include any situation where multiphase flow including gas and liquids may be encountered.

The same damping principles shown in FIG. 5 as a comparison between curves 500 and 502 apply in situations where multiphase flow includes solids and liquids, though to a lesser degree. The multiphase flow can also include a mixture of gas, liquids, and solids. In petroleum industry environments of use, these situations arise where the flow stream includes natural gas, oil or condensate, water, paraffin, sand and/or scale. Thus, the principles of FIGS. 6 and 7 may be used to remediate erroneous density or mass flow rate measurements due to multiphase flow including solids and liquids or gas and solids, as well as gas and liquids.

The above-described process elements are comprised of instructions that are stored on storage media. The instructions can be retrieved and executed by a processor. Some examples of instructions are software, program code, and firmware. Some examples of storage media are memory devices, tape, disks, integrated circuits, and servers. The instructions are operational when executed by the processor to direct the processor to operate in accord with the invention. The term "processor" refers to a single processing device or a group of inter-operational processing devices. Some examples of processors are integrated circuits, computers, and logic circuitry. Those skilled in the art are familiar with instructions, processors, and storage media.

Coriolis flowmeters and associated meter electronics that are equipped to implement the principles of transient bubble remediation discussed above can be used in any environment containing multiphase flow, and the meters work especially well to remediate transient mist and fine bubbles. In this context, "transient" means a flow condition that exists temporarily or periodically over time. The meters also work acceptably well to remediate gas effects in slug flow or plug flow conditions, although, the calculated volumetric flow rates are less reliable under these flow

conditions than for mist flow conditions. Specific applications include chemical processes with gas genesis in a reactor or process flow line, retort processing of foods, microbiological processes with gas genesis, and any other system with multiphase fluids, such as producing wells in the petroleum industry where a separator has not been installed prior to the meter.

A System For Use in Petroleum Well Test Measurements

As shown in FIG. 8, a schematic block diagram, system 800 includes a manifold 802 having a plurality of electronically actuated wellhead valves 803, 803', and 803" that each provide multiphase flow including gas, liquid and solids to tubing 804. Valves 803, 803' and 803" are preferably three-way electronically-initiated, pneumatically actuated valve, such as the Xomox TUFFLINE 037AX WCB/316 well switching valve with a MATRYX MX200 actuator. Valves 803, 803' and 803" are selectively configured to provide multiphase flow from one well at a time through manifold 802 and test line 804 to Coriolis flowmeter 806, which may be the same as Coriolis flowmeter 5. The well flowing through Coriolis flowmeter 806 is under test for its volumetric flow rate to determine its contribution to total sales. The remainder of wells 803, 803' and 803" flow to gathering line 808 for passage through second meter 810, which may be a sales meter. Flow through Coriolis flowmeter 806 discharges into meter discharge line 812 and enters water cut meter 812. The flow is thereafter combined with the flow in gathering line 808 for measurement through second meter 810. Exemplary forms of flowmeters 806 and 810 include the ELITE Models CMF300356NU and Model CMF300H551NU, which are available from Micro Motion of Boulder, Colorado.

System 800 includes a computer 816 (e.g., an IBM compatible machine) that is programmed with data acquisition and programming software. A preferred form of this software is the Intellution software DMACS, which is available from INTELLUTION, a subsidiary of Emerson Electric. This software is particularly preferred because it can generate alarms that indicate abnormal well test conditions representative of mechanical failures which are potentially dangerous. Computer 816 controls the programming of remote operations controller 818, which includes

a plurality of drivers and interfaces that permit computer 816 to interact with remote components of system 800. A preferred form of remote operations controller 818 is the Fisher Model ROC364. Controller 818 may also be programmed with software to facilitate the implementation of control instructions from computer 816.

Valve control leads 820, 820' and 820" connect controller 818 with the electronically actuated valves 803, 803' and 803" for selective control of the valves. Lead 822 connects controller 818 with pressure transmitter 824. An exemplary form of transmitter 824 is the ELITE Model RFT9739, which is available from Micro Motion of Boulder, Colorado. Lead 826 connects controller 818 with water-cut meter 814. The functions of controller 818, transmitter 824, and computer 816 may be combined in a single processor, such as processor 201 of meter electronics 20 (see FIG. 2).

System 800 operates as follows. Manifold 802 cause a single well 803, 803' or 803" to flow through Coriolis flowmeter 806 to test the well or provide mass flow rate information concerning the well while the remainder of the wells flow into gathering line 808 for combined sales output through second meter 810. Coriolis flowmeter 806 provides density and mass flow rate information as meter outputs to transmitter 824 which, in turn, provides signals to controller 818 on lead 822. One of computer 816, controller 818, transmitter 824 or Coriolis flowmeter 806 (typically computer 816) performs a calculation for total volumetric flow rate Q_e according to Equation (4):

$$(4) \quad Q_e = \frac{M_e}{D_e}$$

wherein D_e is a Coriolis-based mass flow rate measurement obtained from the total combined oil and water flow stream; and D_e is a density of the total combined oil, gas, water and solids flow stream at a measurement temperature T .

A volumetric flow rate of oil is calculated according to Equation (5):

$$(5) \quad Q_o = Q_e(1 - X_w)$$

wherein Q_o is a volumetric flow rate of oil; X_w is the fractional flow rate of water, and the remaining variables are defined above.

A volumetric flow rate of water is calculated according to Equation (6):

$$(6) \quad Q_w = Q_e * X_w$$

wherein Q_w is a volumetric flow rate of water, and the remaining variables are defined above.

The volumetric flow rate values Q_o and Q_w can be corrected to a standard reference temperature, T_r , through multiplication of the volumetric flow rate values by the density at a measurement temperature and dividing by the density at the reference temperature, e.g., as in Equation (7):

$$(7) \quad Q_o = Q_{o,T} * \frac{D_{o,T}}{D_o}$$

wherein Q_o is a volumetric oil flow rate at a standard reference temperature T_{ref} ; $Q_{o,T}$ is a volumetric oil flow rate measured at temperature T and calculated according to Equation (5); D_o is a measured density of oil from laboratory measurements at reference temperature T_{ref} ; and $D_{o,T}$ is a density of oil measured at temperature T .

The fractional flow rate of water is calculated as:

$$(8) \quad X_w = \frac{D_e - \rho_{o,T}}{\rho_{w,T} - \rho_{o,T}}$$

wherein D_e is a density of the total combined oil (or condensate) and water flow stream at a measurement temperature T , $\rho_{o,T}$ is a density of the pure oil (or condensate) phase excluding any residual water content of the segregated oil component; $\rho_{w,T}$ is a density of the pure water phase; and the remaining variables are defined above.

The value X_w is a 'water-cut' measurement, which is an important result of well test measurements. The term 'water-cut' is hereby defined as any ratio that

represents a relationship between a volume of oil and a volume of water in an oil and water liquid mixture. Water-cut meter 814 uses capacitance, resistance, microwave radiation or other measurements to quantify the water-cut. In some circumstances, the volume of water is so great that it exceeds the limits of the instrumentation. For example, capacitance or resistance monitors provide acceptably accurate water-cut measurements only where the water volume is less than about 20% to 30% of the total flow stream. The upper 30% accuracy limit is far below the level that is observed from many producing wells. For example, the total liquid production volume of an oil well can be 99% water. Some water-cut monitors, therefore, are relegated to determining the water-cut in an oil component that has a low water content. Water-cut monitors most often cannot be used to determine the water content in the material that flows from a two phase separator because the total liquid component has a water content that exceeds the 30% upper accuracy limit. An exemplary form of water cut monitor 66 is the Drexelbrook Model CM-2 capacitance monitor. Accordingly, Equation (8) provides a method for calculating water cut and the volumetric flow rate of water and oil or condensate. The values $\rho_{o,T}$ and $\rho_{w,T}$ can be obtained from conventional laboratory measurements of produced fluids from a particular well.

Where the value X_w is within the performance and accuracy limits of water cut meter 814, the oil density may be corrected for water content as follows:

$$(9) \quad \rho_{o,T} = \frac{\rho_t - \rho_{w,T}WC}{1 - WC}$$

wherein $\rho_{o,T}$ is water-corrected oil density at temperature T; ρ_t is the total density of the combined water-cut liquid as measured by the Coriolis flowmeter 806 at temperature T; ρ_w is the density of the water component established by laboratory measurement or a conventional empirical temperature-salinity correlation at temperature T; and WC is the water-cut measured by the water-cut monitor 814.

In summary, it is necessary to convert meter liquid measurements from mass flow rates into volumetric flow rates for sales purposes because petroleum products are sold by volume. Density values are used to perform the conversion from mass flow rate into a volumetric flow rate. The fractional flow rates of water and oil are determinable by direct measurement of water cut, but this method does not always work due to instrumentation constraints inherent to water cut meters. The direct measurement of water cut can also be used to calibrate the meter for a changing oil density value over the life of a producing well. Water cut is determinable from the density measurement if the respective densities of water and oil are known from other sources. Gas damping on the system interferes with these calculations according to Equations (8) and (9) because damping may be so severe that the meter ceases to provide accurate density readings of material flowing through the flowtubes or because the measured density represents a sufficient gas content to destroy the assumption of two phase flow that is inherent to Equations (8) and (9). The rate of gas flow can be determined by empirical correlations according to United States Patent No. 5,029,482, which is hereby incorporated by reference to the same extent as though fully disclosed herein.

It follows that computer 816 or controller 818 of FIG. 8 have the option of processing using a density or mass flow rate value obtained according to FIG. 7 while a transient bubble is detected within flowmeter 806. Alternatively, if use of the average value from interval 612 is not desired, alternative options include stopping the well test or indicating an alarm for operator intervention. Yet another option is for computer 816 to signal controller 818 to partially close the selected one of valves 803, 803' or 803" to increase the back-pressure on the well. In the case of an oil well, this backpressure may force liberated gas back into solution, thereby completely or partially overcoming the effects of gas damping on Coriolis flowmeter 806 by the total or partial elimination of gas from the production fluid.

Equations (8) and (9) specifically refer to oil and water, but the equations more broadly refer to any dual phase immiscible liquid system, e.g., any colloidal solution, that may also be affected by gas as a third phase. The deleterious effects

of gas upon these systems includes more than mere damping because X_w values calculated using the density from equation (8), as corrected by Equation (9), has error due to the reduced density value D_e when the equations were developed on the assumption of dual phase immiscible liquids without taking gas into consideration.

Those skilled in the art will understand that the preferred embodiments described above may be subjected to apparent modifications without departing from the true scope and spirit of the invention. The inventor, accordingly, hereby states his intention to rely upon the Doctrine of Equivalents, in order to protect his full rights in the invention.

CLAIMS:

1. A Coriolis flowmeter capable of use as a vibrating densitometer in multiphase flow environments including combinations of gas and liquids, gas and solids, or solids and liquids, said flowmeter comprising:

at least one flowtube;

means for vibrating said flowtube at a fundamental frequency corresponding to a density of material flowing through said flowtube;

means for monitoring drive gain in vibrating said flowtube for a change in value to determine the existence of multiphase flow through said flowtube; and

means for responding to said monitoring means when said monitoring means determines the existence of multiphase flow in said flowtube.

2. The flowmeter as set forth in claim 1 wherein said monitoring means includes means for comparing said drive gain to a threshold value to determine if said drive gain exceeds said threshold value as an indicator of multiphase flow.

3. The flowmeter as set forth in claim 2 wherein said threshold value is indicative of multiphase flow including gas and liquids.

4. The flowmeter as set forth in claim 3 wherein said monitoring means includes means for comparing said drive gain to a second threshold value to determine if said drive gain exceeds said second threshold value as an indicator of multiphase flow including liquid and solid matter.

5. The flowmeter as set forth in claim 1 wherein said responding means includes means for providing a density value other than a density value corresponding to said fundamental frequency.

6. The flowmeter as set forth in claim 5 wherein said providing means includes means for retrieving data representative of historical density measurements from said flowtube for use as said other density value.

7. The flowmeter as set forth in claim 6 wherein said historical density measurements are averaged over an interval of time to provide an average density value.

8. The flowmeter as set forth in claim 7 wherein said historical density measurements are subjected to statistical analysis to eliminate or reduce spurious measurements from being included in said average density value.

9. The flowmeter as set forth in claim 5 wherein said providing means includes means for retrieving data representative of density measurements obtained from laboratory measurements for use as said other density value.

10. The flowmeter as set forth in claim 5 wherein said providing means includes means for retrieving data representative of density measurements obtained from a correlation for use as said other density value.

11. The flowmeter as set forth in claim 1 wherein said flowmeter is operably coupled with a producing well for the conduct of measurements upon fluid flowing from said well, and said responding means includes means for stopping a well test in progress upon production flowing from said well.

12. The flowmeter as set forth in claim 1 wherein said flowmeter is operably coupled with a producing well for the conduct of measurements upon fluid flowing from said well, and said responding means includes means for indicating an alarm indicative of said multiphase flow.

13. The flowmeter as set forth in claim 1 wherein said responding means includes means for providing drive gain as a meter output.

14. A method of operating a Coriolis flowmeter as a vibrating tube densitometer, said method comprising the steps of:

vibrating at least one flowtube of a Coriolis flowmeter at a fundamental frequency corresponding to a density of material flowing through said flowtube;

monitoring drive gain in vibrating said flowtube for a change in value to determine the existence of multiphase flow through said flowtube; and

responding to said monitoring means when said monitoring means determines the existence of multiphase flow in said flowtube.

15. The method as set forth in claim 14 wherein said step of monitoring drive gain includes comparing said drive gain to a threshold value to determine if said drive gain exceeds said threshold value as an indicator of multiphase flow.

16. The method as set forth in claim 15 wherein said step of comparing includes setting said threshold value as an indicator of multiphase flow including gas and liquids.

17. The method as set forth in claim 16 wherein said step of comparing includes comparing said drive gain to a second threshold value to determine if said drive gain exceeds said second threshold value as an indicator of multiphase flow including liquid and solid matter.

18. The method as set forth in claim 14 wherein said step of responding includes providing a density value other than a density value corresponding to said fundamental frequency.

19. The method as set forth in claim 18 wherein said step of providing includes a step of retrieving data representative of historical density measurements from said flowtube for use as said other density value.

20. The method as set forth in claim 19 including a step of averaging said historical density measurements are averaged over an interval of time to provide an average density value.

21. The method as set forth in claim 20 including a step of subjecting said historical density measurements to statistical analysis to eliminate or reduce spurious measurements from being included in said average density value.

22. The method as set forth in claim 18 wherein said providing means includes means for retrieving data representative of density measurements obtained from laboratory measurements for use as said other density value.

23. The flowmeter as set forth in claim 18 wherein said providing means includes means for retrieving data representative of density measurements obtained from a correlation for use as said other density value.

24. A product comprising:
instructions operational when executed by a processor to direct the processor to
receive drive gain inputs from a Coriolis meter and process the drive gain inputs,

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process the drive gain inputs to determine the existence of multiphase flow through said Coriolis flowmeter by comparing said drive gain inputs against a threshold value indicative of multiphase flow, and

providing outputs including a historical density value not representative of actual density measurements for the duration of said multiphase flow; and
a storage medium operational to store said instructions.

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ABSTRACT

A Coriolis flowmeter is operable as a vibrating tube densitometer where a flowtube is driven to vibrate at a fundamental frequency from which density of the material flowing through the flowtube may be calculated. The drive gain is monitored as an indicator of multiphase flow including gas and liquid components where a substantial increase in drive gain indicates gas damping of the flowtube vibrations due to a transient bubble entering the flowtube. The gas damping effects of the transient bubble and the correspondingly reduced density readings are remediated by the use of historical density measurements corresponding to periods of flow when no transient bubble has entered the flowtube.

FIG. 1 is a schematic diagram of a system 5 for measuring a parameter of a fluid flow in a pipe 100. The system 5 includes a meter electronics unit 20 and a sensor assembly 10. The sensor assembly 10 is connected to the meter electronics unit 20 via a cable 110. The sensor assembly 10 includes a sensor 101 and a transducer 102. The sensor 101 is positioned to measure the fluid flow in the pipe 100. The transducer 102 is connected to the sensor 101 and the meter electronics unit 20. The meter electronics unit 20 is connected to a power source 26. The sensor assembly 10 is also connected to a data output 26. The sensor assembly 10 is shown in a cross-sectional view, with the sensor 101 and transducer 102 positioned within the pipe 100. The sensor 101 is connected to the transducer 102 via a cable 103A. The transducer 102 is connected to the meter electronics unit 20 via a cable 103B. The meter electronics unit 20 is connected to the power source 26 via a cable 104. The meter electronics unit 20 is also connected to the data output 26 via a cable 105. The sensor assembly 10 is shown in a perspective view, with the sensor 101 and transducer 102 positioned within the pipe 100. The sensor 101 is connected to the transducer 102 via a cable 103A. The transducer 102 is connected to the meter electronics unit 20 via a cable 103B. The meter electronics unit 20 is connected to the power source 26 via a cable 104. The meter electronics unit 20 is also connected to the data output 26 via a cable 105. The sensor assembly 10 is shown in a perspective view, with the sensor 101 and transducer 102 positioned within the pipe 100. The sensor 101 is connected to the transducer 102 via a cable 103A. The transducer 102 is connected to the meter electronics unit 20 via a cable 103B. The meter electronics unit 20 is connected to the power source 26 via a cable 104. The meter electronics unit 20 is also connected to the data output 26 via a cable 105.

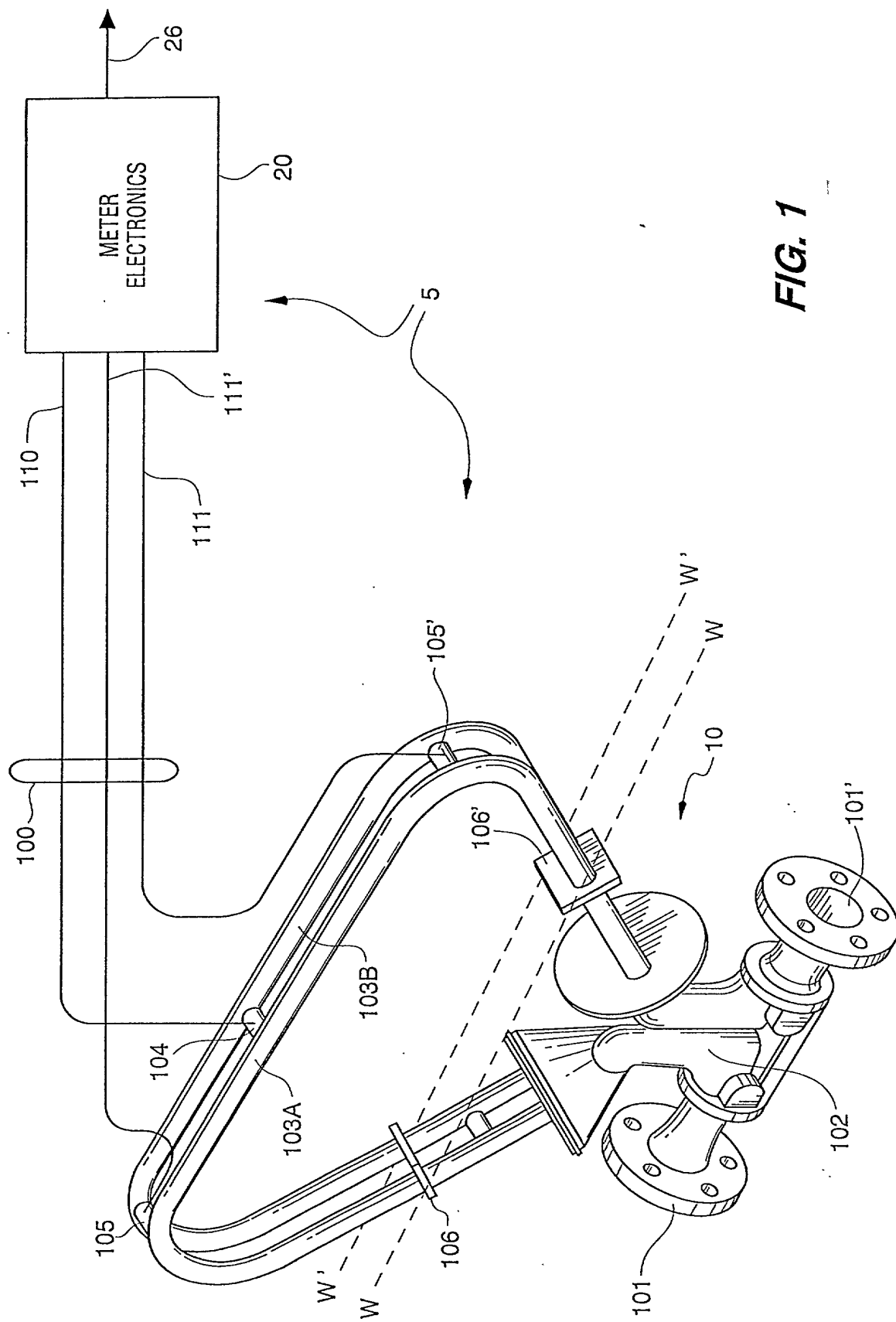
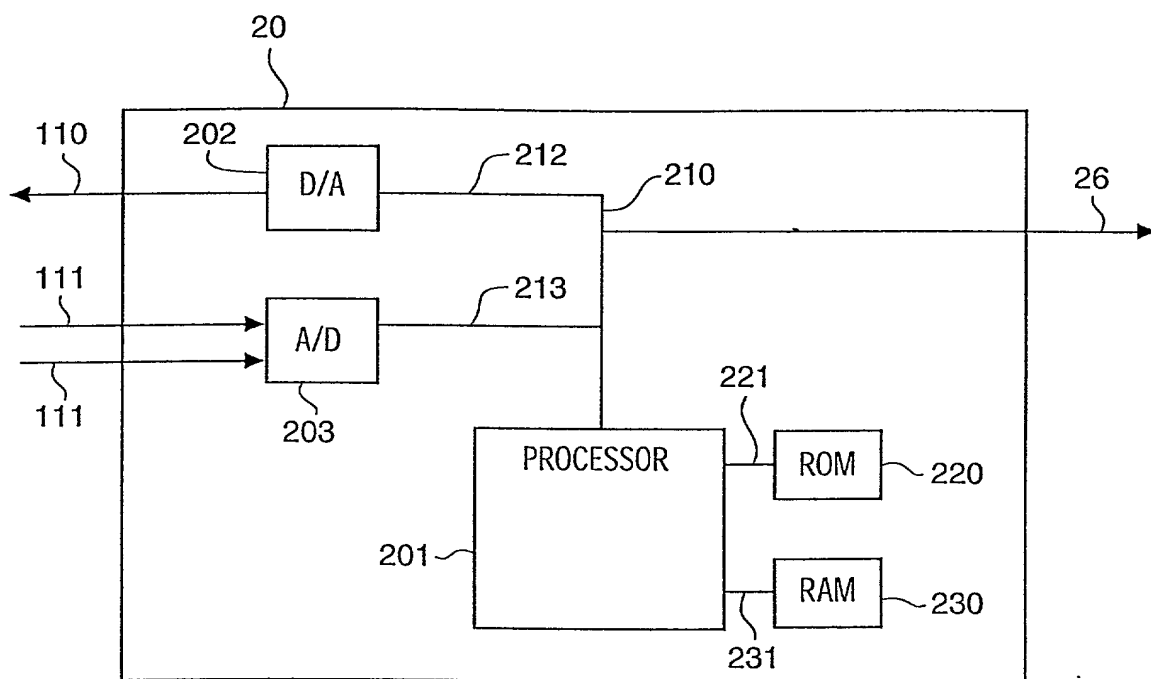


FIG. 1

FIG. 2



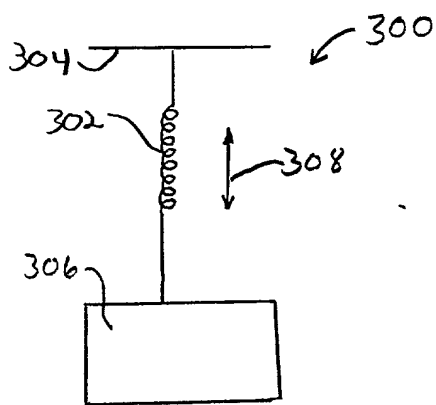


FIG. 3

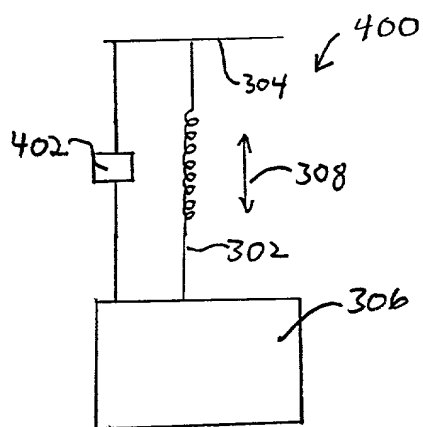


FIG. 4

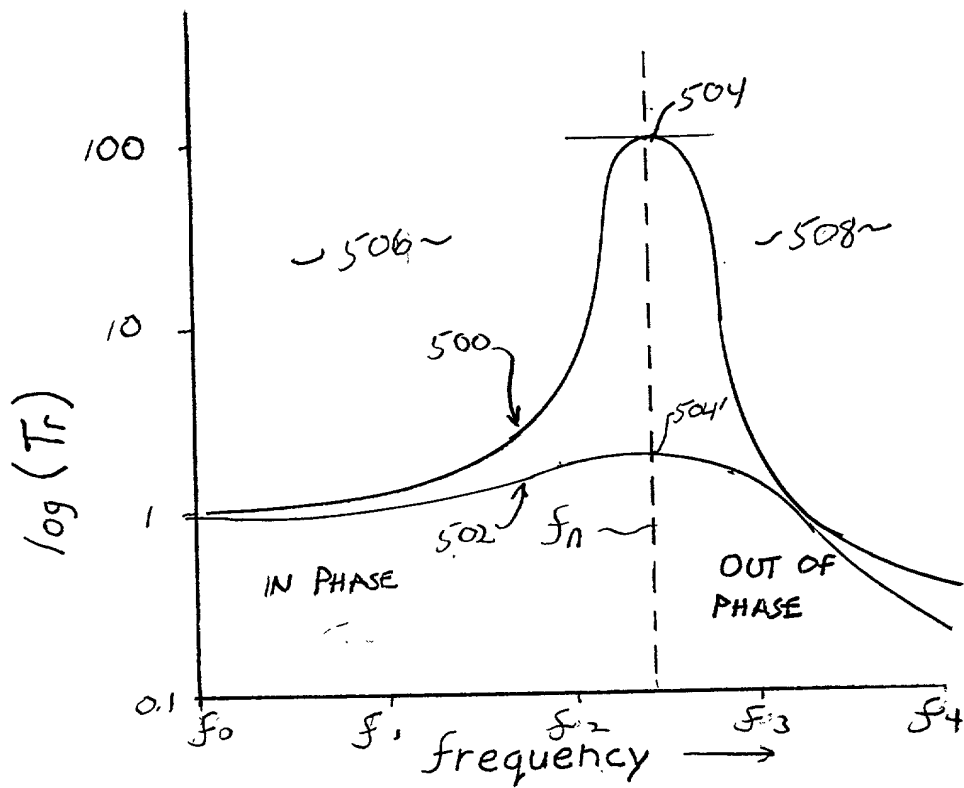


FIG. 5

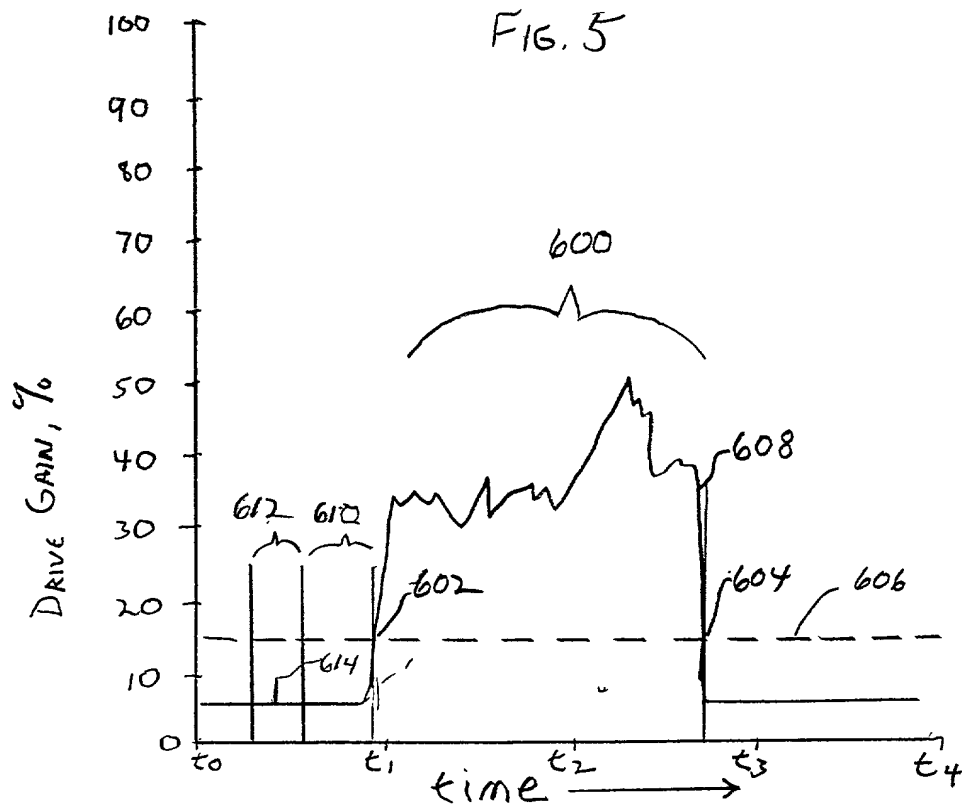
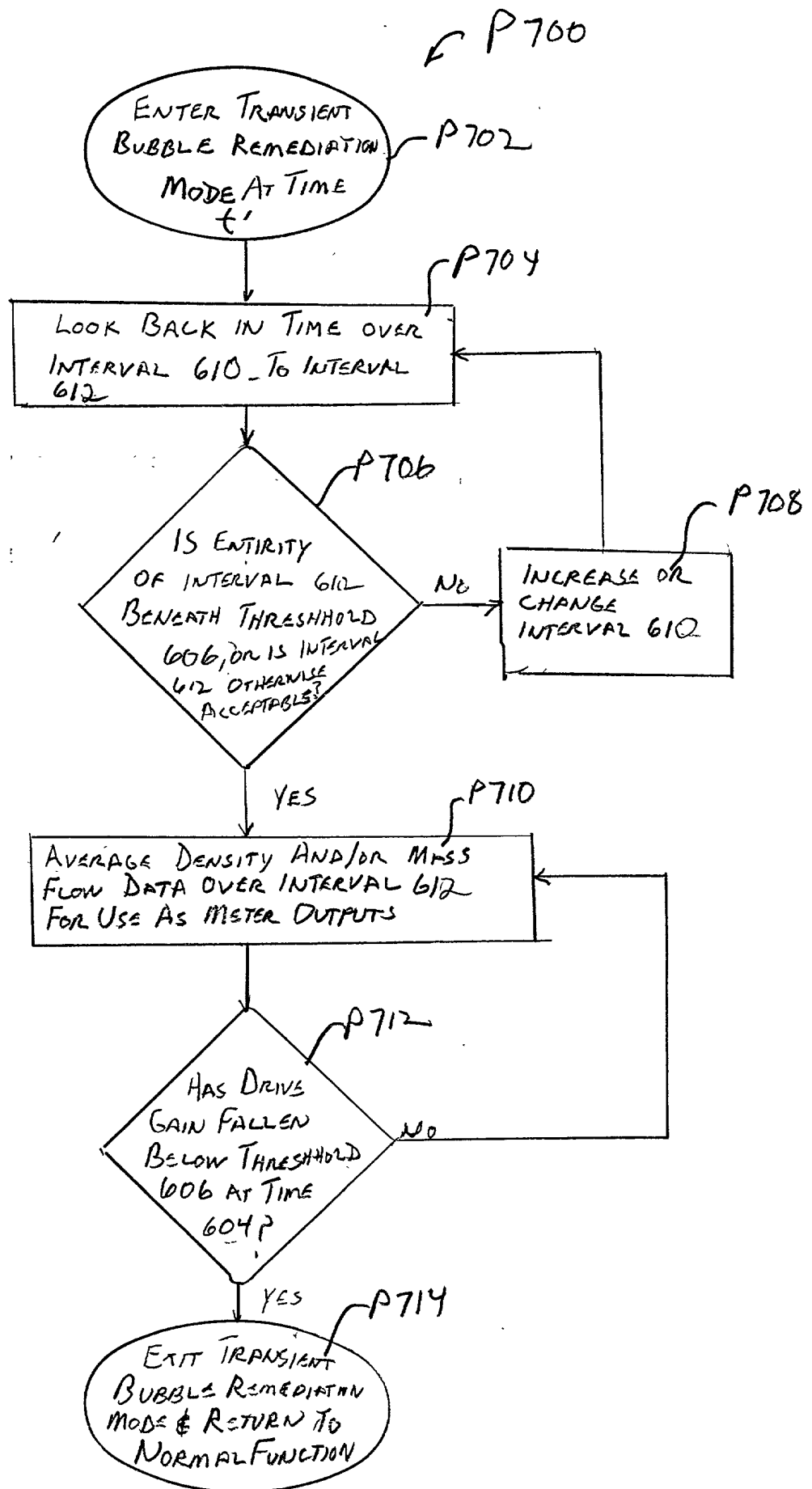
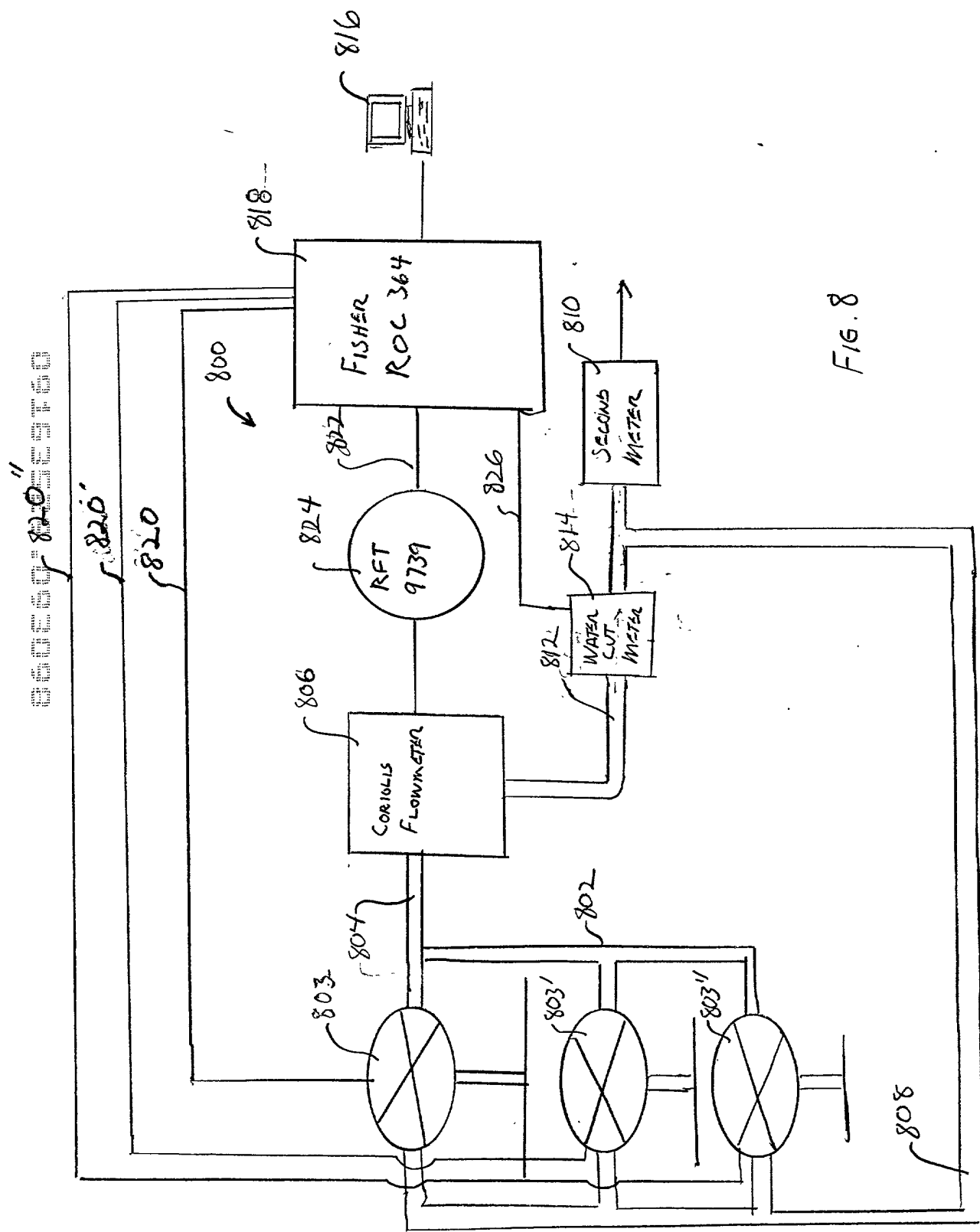


FIG. 6

FIG. 7





DECLARATION FOR PATENT APPLICATION

Docket Number: 7003/036

As a below named inventor, I hereby declare that:

My residence, post office address and citizenship are as stated below next to my name. I believe I am the original, first and sole inventor (if only one name is listed below) or an original, first and joint inventor (if plural names are listed below) of the subject matter which is claimed and for which a patent is sought on the invention entitled

TRANSIENT BUBBLE REMEDIATION IN CORIOLIS FLOWMETERS

the specification of which is attached hereto unless the following is checked:

_____ was filed on _____ as United States Application Numbers _____ or PCT International Application Number _____ and was amended on _____ (if applicable).

I hereby state that I have reviewed and understand the contents of the above-identified specification, including the claims, as amended by any amendment referred to above.

I acknowledge the duty to disclose information which is material to patentability as defined in Title 37, Code of Federal Regulations, § 1.56.

I hereby claim foreign priority benefits under Title 35, United States Code, §119 of any foreign application(s) for patent or inventor's certificate listed below and have also identified below any foreign application for patent or inventor's certificate having a filing date before that of the application on which priority is claimed.

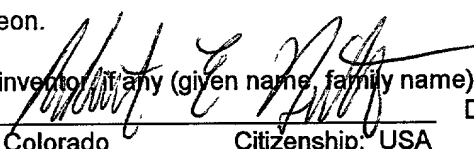
Prior Foreign Application(s)			Priority Claimed
(Number)	(Country)	(Day/Month/Year Filed)	___ Yes ___ No

I hereby claim the benefit under Title 35, United States Code, §120 of any United States application(s) listed below and, insofar as the subject matter of each of the claims of this application is not disclosed in the prior United States application in the manner provided by the first paragraph of Title 35, United States Code, §112, I acknowledge the duty to disclose information which is material to patentability as defined in Title 37, Code of Federal Regulations, §1.56 which became available between the filing date of the prior application and the national or PCT international filing date of this application.

Application No. _____	Filed: _____	Status: pending
Application No. _____	Filed: _____	Status: _____

I hereby appoint the following attorney(s) and/or agent(s) to prosecute this application and to transact all business in the U.S. Patent and Trademark Office connected therewith: Donald M. Duft 17,484; James M. Graziano 28,300; Carl A. Forest 28,494; Dan Cleveland, Jr. 36,106; Michael J. Setter 37,936; William P. Wilbar 43,265; Curtis A. Vock 38,356; Kirk D. Williams 42,229; and Steven W. Weinrieb 26,520. Address all telephone calls to Dan Cleveland, Jr., Esq. at Telephone No. (303) 449-9497 and address all correspondence to Dan Cleveland, Jr., DUFT, GRAZIANO & FOREST, P.C., 1790 - 30th Street, Suite 140, Boulder, Colorado 80301-1018.

I hereby declare that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issued thereon.

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